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Analytical model for solar PV and CSP electricity costs: Present LCOE values and their future evolution

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ABSTRACT

In this paper we first make a review of the past annual production of electricity and the cumulative installed capacity for photovoltaic (PV) and concentrating solar power (CSP) technologies. This together with the annual costs of PV modules and CSP systems allows us the determination of the experience curves and the corresponding learning rates. Then, we go over a rigorous exposition of the methodology employed for the calculation of the value of the levelized cost of electricity (LCOE) for PV and CSP. Based on this knowledge, we proceed to establish a mathematical model which yields closed-form analytical expressions for the present value of the LCOE, as well as its future evolution (2010–2050) based on the International Energy Agency roadmaps for the cumulative installed capacity. Next, we explain in detail how specific values are assigned to the twelve independent variables which enter the LCOE formula: solar resource, discount and learning rates, initial cost and lifetime of the system, operational and maintenance costs, etc. With all this background, and making use of a simple computer simulation program, we can generate the following: sensitivity analysis curves, graphs on the evolution of the LCOE in the period 2010–2050, and calculations of the years at which grid parities will be reached. These representations prove to be very useful in energy planning policies, like tariff-in schemes, tax exemptions, etc., and in making investment decisions, since they allow, for a given location, to directly compare the costs of PV vs CSP power generation technologies for the period 2010–2050. Among solar technologies, PV seems always more appropriate for areas located in middle to high latitudes of the Earth, while CSP systems, preferably with thermal storage incorporated, yield their best performance in arid areas located at relatively low latitudes.

Contents

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1. Introduction

During the last decades, the production of electricity from sunlight has been increasing at a very high pace. This is specially true in the case of photovoltaic (PV) solar energy, which has shown an annual growth rate of about 40% during the last decade [1]. With respect to concentrating solar power (CSP), the growth in electricity production has not been so steady, but nevertheless, has more than tripled in the last five years [2]. Although the growth rate of solar power generation has been very huge in relative terms, at present it only represents about 0.2% of the global electricity production and 4.7% of all renewable energy, excluding hydroelectricity [3].

This great relative increase of renewable solar electricity production has been mainly spurred by the adverse effects of CO_2 emissions, the highly increasing prices of fossil fuels, and the need of assuring additional energy supplies. For all these reasons, the International Energy Agency (IEA) and many governments are reinforcing plans for a substantial deployment of renewable energy production. In this sense, the 2010 PV and CSP roadmaps elaborated by the IEA [1,4] forecast for the year 2050 a participation of up to 22% of solar production (11% each) in the global electricity generation mix. This means that PV and CSP electricity generation would have to increase by factors of 80 and 1000, respectively, during the next four decades, the large difference being due to the much greater cumulative installed capacity of PV in comparison to CSP at present. Furthermore, due to recent decrease of PV systems costs, it is probable that the participation of PV systems could be even greater than the one estimated.

Until now, one of the main factors that have slowed down a larger deployment of solar electricity by utilities is that, even for sites with a relatively high solar resource, the solar electricity generation costs for PV and CSP approximately double or triple the cost of the electricity provided by the current grid. Although this might seem still a very large difference, the expectations are that, due to the laws of mass production and experience learning, future costs of solar electricity generation will come down substantially in the next decades. This general assumption mainly rests on the argument of the large increase foreseen during the next four decades in solar power generation as discussed above. We can also add in favour of a future convergence of costs the facts that the prices of fossil fuels will probably increase in the future and that external costs attributed to CO_2 emissions will be more intensively applied.

In this paper, we develop a mathematical model for solar electricity costs, one of the aims being the comparison between PV and CSP costs under different situations. To this end, we make use of discounted cash flow (DCF) economic techniques, for the calculation of both the present value of the levelized cost of electricity (LCOE), and its future evolution for the period (2010–2050). The LCOEs have been rigorously calculated taking into account the remarks underlined by several previous studies [5–7]. For the study of the cost evolution of the LCOEs, we have made use of the experience curves and the values of the learning rates recommended by the IEA. The present model for PV and CSP systems is partially based on a simpler one that we previously developed only for CSP systems [8]. This method also allows estimating the years in which PV and CSP grid parities will be attained as well as the calculation of the sensitivity factors. Finally, we would like to remark that one important aspect that directly emanates from our method is that the calculation of the future evolution of the LCOEs not only depends on the predictions made by the IEA for the values of the cumulative installed capacity, $Q(t)$, but is also strongly influenced by the specific curved time-paths followed by this function.

As we show in this work, the model can be readily applied to both PV and CSP, in spite of their large differences, not only in the technological aspects, but also in the way the solar resource is exploited: whilst PV takes advantage of the direct and diffuse solar irradiation, CSP only captures the direct component [9]. Since our technique is based on a set of closed analytical expressions, we can directly plot, using simple mathematical software, the future cost evolution of PV and CSP electricity for any set of values of the independent variables, such as the solar resource, initial cost of the systems, financial discount rate, etc. Feed in tariffs and other fiscal and regulatory instruments have been traditionally used to encourage solar energy production [10–14]. Our model also allows estimating the most adequate feed-in tariff for PV and CSP systems, as previously done by Zahedi [15] for PV systems.

2. Present PV and CSP status

Fig. 1 shows for PV systems the evolution, from 1990 to the end of 2010, of both the cumulative installed capacity and the annual electricity production. Data for the cumulative installed capacity, collected from several sources [12,16–19], show a steady increase since 1990, with an annual average growth rate of 40% during the last decade [1]. More than 90% of the current total installed capacity corresponds to grid-connected systems, while stand alone systems, the large majority of them integrated into buildings, account for the rest [1,20]. Among PV technologies, crystalline silicon system account for 85–90% of the annual market today, while thin film systems correspond to the rest of the sales [1]. At the end of 2010, when the cumulative installed capacity was about 40 GW, only five countries accounted for more than 78% of the cumulative installed capacity [19]: Germany

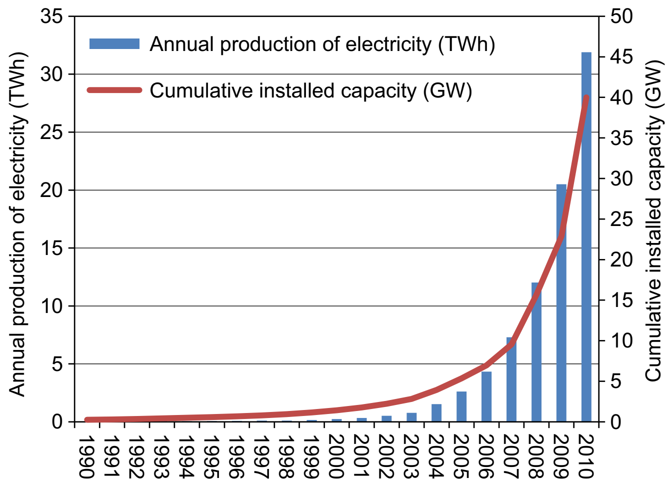


Fig. 1. PV global cumulative installed capacity (GW) and annual electricity production (TW h) between 1990 and 2010 (data compiled from several sources, see text).

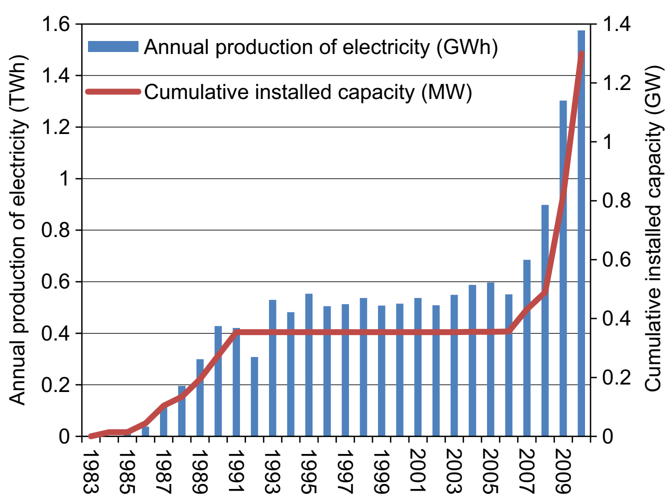


Fig. 2. CSP global cumulative installed capacity (GW) and annual electricity production (TW h) between 1983 and 2010 (data compiled from several sources, see text).

(44%), Spain (10%), Italy (9%), Japan (9%) and USA (6%). The annual PV electricity production between 1990 and 2010, represented in Fig. 1, has been compiled from several sources [3,21].

Fig. 2 represents the cumulative installed capacity and the annual production of electricity for CSP systems between 1983 and 2010 [2,21–28]. The strong initial increase in the 1980s occurred mainly in the US, partly as a result of notable federal and state tax incentives that led to the installation of the SEGS plants (I to IX) in the Mojave Desert, California [4,29]. The 15 years of inactivity that followed was only reversed in 2006, when the market reemerged in Spain and the United States [4]. At the end of 2010 there were 1.3 GW of commercial CSP capacity installed worldwide [2], of which more than 90% were parabolic trough systems [30]. This technology is still the most mature CSP technology [26,30], although CSP tower systems projects have recently gained considerable importance [7,31]. At present, Spain and the United States dominate the market in terms of cumulative installed capacity, with market shares of 55.4% and 38.5%, respectively [7,28]. The annual CSP electricity production between 1983 and 2010, represented in Fig. 3, has been compiled from several sources [21,24,25].

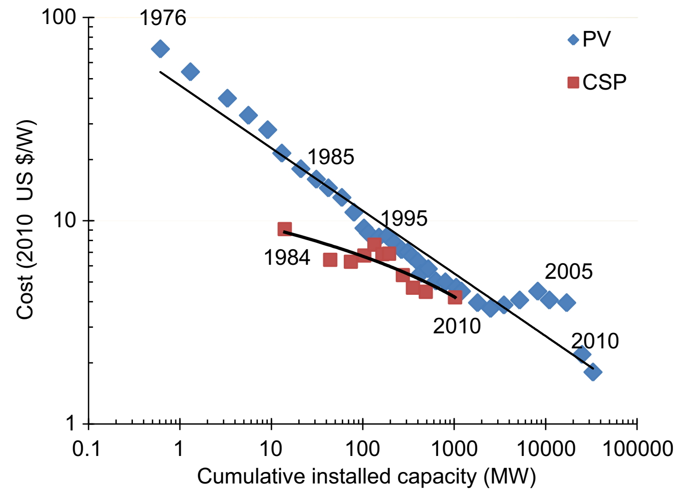


Fig. 3. Learning curves in log–log space, given in 2010 US$, for PV modules (square points) between 1976 and 2010 and for CSP systems (rhombus points) between 1984 and 2010. Personal elaboration based on several sources (see text).

3. Basis of the analytical model for the calculation of the LCOE solar electricity cost and its future evolution

The mathematical model for the calculation of the levelized cost of energy (LCOE) of solar technologies (PV and CSP) and its future evolution that we propose in this work expresses these costs by means of a closed-form equation which provides analytical solutions. Therefore we can estimate the LCOE for PV and CSP technologies, and compare them for a particular place, introducing directly the corresponding local data (solar irradiation, discount rate, etc.). Our model also allows undertaking a sensitivity analysis for different variables that affect the LCOE. In this section, we explain in 3.1, how to estimate the levelized cost of energy (LCOE) for PV and CSP technologies using discount cash flow (DCF) techniques. Next, in 3.2, we explain how to estimate the future evolution of the LCOE between 2010 and 2050 by means of the learning curve approach.

3.1. The LCOE formula for solar electricity costs

The economic feasibility of an electricity generation project can be evaluated by various methods, but the LCOE is the most frequently used when comparing electricity generation technologies or considering grid parities for emerging technologies [5,7,32]. The model calculates the cost of solar electricity during the whole lifetime of the systems, whilst other models [11,33–35] estimate that cost annually. We make all these precisions so that all the variables entering the formulas that follow have always a precise meaning. Making use of a life-cycle technique to estimate the LCOE, the expenses and sales revenues that occur in a future time have to be accounted for the present time value of money. This is done using discounted cash flow (DCF) techniques, i.e., by calculating the present value of the cash flows by means of a discount rate, r. In this context, the LCOE is determined when the present value of the sum of the discounted revenues is equivalent to the discounted value of the sum of the costs during the economic lifetime of the system, N years [36], i.e.,

$$\sum_{n=0}^{N} \frac{\text{Revenues}_n}{(1+r)^n} = \sum_{n=0}^{N} \frac{\text{Costs}_n}{(1+r)^n} \tag{1}$$

Thus, the Net Present Value (summation of the present values, PV, of the cash flows), NPV, of the project is zero [36,37], i.e.,

$$\text{NPV} = \sum_{n=0}^{N} \text{PV} = 0 \tag{2}$$

Therefore the LCOE is the average electricity price needed for a Net Present Value (NPV) of zero when performing a discounted cash flow (DCF) analysis, so that an investor would break even and so receive a return proportional to the discount rate of the investment [6,7,38–41]. The sum of the present values of the $LCOE_n$ multiplied by the energy generated annually, E_n, should be equal to the sum of the present values of the costs of the project, i.e.,

$$\sum_{n=0}^{N} \frac{(LCOE_n)\times(E_n)}{(1+r)^n} = \sum_{n=0}^{N} \frac{Costs_n}{(1+r)^n} \tag{3}$$

Assuming a constant annual value for the LCOE, we can write:

$$LCOE = \left(\sum_{n=0}^{N} \frac{Costs_n}{(1+r)^n}\right) \Bigg/ \left(\sum_{n=0}^{N} \frac{E_n}{(1+r)^n}\right) \tag{4}$$

Note that while it appears in Eq. (4) as if the energy is being discounted, it is just an arithmetic result of rearranging Eq. (3) [5,32]. Hence, according to Eq. (4), the LCOE equals to the sum of all the discounted costs incurred during the lifetime of the project divided by the units of discounted energy produced. It should be noted that the summation calculation starts from $n=0$ to include the initial cost of the project at the beginning of the first year, which should not be discounted. Therefore, we can include the initial cost outside the summation and start the summation at $n=1$ both in the numerator and in the denominator, i.e.,

$$LCOE = \left(\text{Initial Costs} + \sum_{n=1}^{N} \frac{\text{Annual Costs}_n}{(1+r)^n}\right) \Bigg/ \left(\sum_{n=1}^{N} \frac{E_n}{(1+r)^n}\right) \tag{5}$$

Among the capital costs, that are paid up-front, and therefore do not have to be discounted, we will consider the cost of the system, C, and the cost of the required land, L. These initial costs represent a significant part of the total investment (as much as 80% for PV systems) and are very dependent on the market segment [32]. The remainder of the expenditures is paid annually over the lifetime of the systems, and therefore they should be discounted. Among these annual costs we will consider operation and maintenance costs, $OPEX_n$, and insurance costs, I_n. If we evaluate these costs as a constant percentage (OPEX and I, respectively) of the costs of the system, C, then we can write:

$$OPEX_n + I_n = (OPEX + I) \times C \tag{6}$$

On the revenue side, every unit of energy produced (kW h) corresponds to a flow of income over the entire lifetime of the system, and, as explained before, they should be discounted. Next, we consider the annual energy production, E_n, as being directly proportional to the available solar resource, S. In addition, there are other factors that affect E_n, which will be treated in detail in Section 4. They are the tracking factor, TF, the annual degradation rate, d, and the performance factor, η, which relates the amount of the utilized solar resource to the quantity of electricity produced. Therefore, we can write for the energy produced during the nth year:

$$E_n = S \times TF \times \eta \times (1-d)^n \tag{7}$$

Both the costs and the energy produced should be given per installed watt, i.e., \$/W and kW h/W units, respectively, obtaining the LCOE in \$/kW h units. Finally, from Eqs. (5)– (7), we can write for the LCOE:

$$LCOE = \left(C + L + \sum_{n=1}^{N} \frac{(OPEX+I)\times C}{(1+r)^n}\right) \Bigg/ \left(\sum_{n=1}^{N} \frac{S \times TF \times \eta \times (1-d)^n}{(1+r)^n}\right) \tag{8}$$

To convert this expression for the LCOE solar electricity costs into analytical equations yielding numerical values, we still have to clearly show (Section 4) how the different variables entering into the model are evaluated for a given situation.

3.2. Future evolution of the LCOE using the learning curve approach

Next we explain how to estimate the evolution of the levelized cost of energy produced by PV and CSP systems, LCOE(t), where t refers to the specific year, in the (2010–2050) interval, when the new systems are installed. In what it follows, all costs will be given in constant (real) 2010 US Dollars, so that they are not distorted by inflation rates. The time dependence of the LCOE(t) arises mainly through the cost of the systems, $C(t)$, that we have considered that will evolve in the future in accordance with the learning curve approach, as discussed below.

Several studies carried out during the last decades [42,43] have demonstrated that the costs of producing manufactured goods tend to decline continuously according to the economics of scale [44]. In particular, this is the case of electricity production from renewable sources. The reduction in the production costs is characterized by the so-called learning curves, or experience curves, which have become a powerful and widely used tool for projecting technological change [45–47], since they describe past evolution of the cost of the systems as a function of the cumulative installed capacity. The learning curves plot as straight lines in log–log space, as shown in Fig. 3, where past learning curves for PV modules and CSP systems have been represented expressed in constant 2010 US\$ per installed watt. The slope of these lines is related to the learning rate (LR) which indicates the cost reduction in percentage per cumulative doubling of installed capacity. The data of Fig. 3 corresponding to the costs of PV modules between 1976 and 2010 has been collected from several sources [48–50], and show a learning rate of around 20%. For CSP systems we have obtained a learning rate of 11% between 1984 and 2010 using the data compiled from several sources [4,51,52]. In order to compare the evolution of PV and CSP systems costs, in Fig. 3 we have converted all PV and CSP costs into constant 2010 US\$ using the corresponding annual inflation data in the United States [53].

Since the learning curves in log–log space in Fig. 3 correspond to straight lines, their equations, in terms of the cost (C) and the cumulative installed capacity (Q), at moments "t_1" and "t_2" can be expressed as:

$$\text{Log}(C(t_2)) = -b \times (\text{Log}(Q(t_2)) - \text{Log}(Q(t_1))) + \text{Log}(C(t_1)) \tag{9}$$

or in normal space [44,46,50,54]:

$$\frac{C(t_2)}{C(t_1)} = \left(\frac{Q(t_2)}{Q(t_1)}\right)^{-b} \tag{10}$$

The exponent $-b$ represents the slope of the straight line in log–log space, and since the learning rate LR indicates by definition the cost reduction per cumulative doubling of installed capacity, they should be related, from Eq. (10), by

$$1-LR = 2^{-b} \rightarrow -b = \text{Log}(1-LR)/\text{Log}(2) \tag{11}$$

Therefore, the cost of the new systems installed in a future year t, between 2010 and 2050, $C(t)$, will be given, from Eqs. (10) and (11), by:

$$C(t) = C(0)\left(\frac{Q(t)}{Q(0)}\right)^{\text{Log}(1-LR)/\text{Log}(2)} \tag{12}$$

This equation implies that $C(t)$ can be calculated from the initial cost of the system, $C(0)$, the initial cumulative installed capacity, $Q(0)$, the cumulative installed capacity at a year t, $Q(t)$, and the learning rate, LR. Therefore, according to Eqs. (8) and (12),

the LCOE for the electricity produced by the systems installed at a year t, can be expressed as:

$$\mathrm{LCOE}(t)=\left(C(0)\left(\frac{Q(t)}{Q(0)}\right)^{\frac{Log(1-LR)}{Log(2)}}+L+\sum_{n=1}^{N}\frac{(\mathrm{OPEX}+I)\times C(0)\left(Q(t)/Q(0)\right)^{\frac{Log(1-LR)}{Log(2)}}}{(1+r)^n}\right)\Bigg/\left(\sum_{n=1}^{N}\frac{S\times TF\times\eta\times(1-d)^n}{(1+r)^n}\right) \tag{13}$$

The next step to follow is to assign to each of the independent variables in Eq. (13) the specific values corresponding to both (PV, CSP) power generating systems located in a given geographical site. In this way, we will be able to find relatively simple analytical expressions that will allow to directly plot, by means of a simple computer simulation program, the LCOE present costs, and their evolution, as well as performing sensitivity analysis (Section 5).

4. Factors considered in the model

In our model, we take PV crystalline-silicon and CSP parabolic trough systems as the reference systems to calculate the cost of large-scale solar electricity generation, due to their dominant market position (see Section 2) and since they are the most mature and reliable systems at present. In this sense, a very important factor in favor of Si-crystalline cells is their already proven long life of about 25–30 years [1]. However, this does not imply that, in a future time, it could not happen a major shift of the market to a less expensive technology, like thin films, organic cells, or dye-sensitized cells [55–58]. In a more distant future, cells based in new phenomena will hopefully contribute to the lowering of the learning curve. Among these phenomena, often based in nanotechnologies, we would like to highlight photon interconversion (photon addition and photon cutting), intermediate level devices, impact ionization for the creation of more than one electron–hole pairs, etc. [59,60]. In fact, situations like these are what have conducted experts to forecast a future continuation of the high value of the learning rate for PV systems.

In this section we describe in detail the factors that directly affect the LCOE present value and its future evolution for PV and CSP systems, and specify the particular range of values that we assume they take. We have grouped the factors which are closely related among themselves in order to simplify the understanding of the model.

4.1. Initial investment

First we consider those costs that are paid up-front, which as explained in Section 3, are the cost of the system, C, and the cost of the required land, L.

4.1.1. Cost of PV and CSP systems

Total PV system costs are composed of the sum of module costs, that account for roughly 60% of the total cost [20], plus the expenses for the "balance of system" (BOS), which covers all the additional equipment needed to convert the direct current from the solar modules to alternating current. While the production costs vary strongly among the different PV module technologies, the differences are less significant at the system level. For the crystalline silicon technology, the IEA has reported that typical turn-key prices range from 4 \$/Wp for utility scale (multi-megawatt applications), to 6 \$/Wp for small-scale applications in the residential sector [1]. Although the more recently reported prices for PV systems in 2010 are even lower [6,61,62], we will take in this work the above more conservative data from the IEA as our reference case.

Current reported investment costs for installed parabolic trough systems range between 4 \$/W and 8.7 \$/W [4,7,34,63–71] depending on the local labour costs, the amount of storage and the size of the solar field. As parabolic trough plants are always centralized electricity generation systems of utility scale, the differences between the costs of specific plants will be mainly determined by the amount of thermal storage. Therefore, we will compare in this work the cost of systems without thermal storage of 4.2 \$/W, corresponding f.i. to Nevada Solar One in the United States [51], with another plant with 7.5 h of molten salt thermal storage with a cost of 8.6 \$/W, corresponding f.i. to Andasol 1 in Spain [34].

4.1.2. Land cost

The price of land is one of the most difficult costs to estimate since it varies widely depending on the location. The specific area demanded for a parabolic trough power plants is about 1 km^2 per 50 MW of installed electric capacity [4,27,72]. Consequently, for an average value of the land, the specific land cost per watt considered in this work will be 24 \$/kW [63]. PV plants use between 10 and 50 km^2/GW [73], and consequently the land cost ranges widely between 12 and 60 \$/kW. In this work, we have estimated the land cost for PV systems to be 30 \$/kW. We have considered only the land costs for centralized generation PV plants, like the ones used by utilities, since the cost for distributed generation systems should be nearly zero as they take advantage of the roofs of the buildings, parking, etc.

4.2. Annual costs

4.2.1. Operation and maintenance costs

Operation and maintenance costs during the whole lifetime of solar PV and CSP systems installed at a year t, in contrast to those of traditional power plants, are quite low since fuel consumption is practically null. PV systems without trackers do not have moving parts, so operating and maintenance costs consist of regular cleaning, monitoring of performance and inverter replacement approximately every 10 years [74,75]. Actual inverter costs range between 0.25–0.4 \$/W [75,76], even though inverter reliability and cost are both improving rapidly [77,78]. CSP O&M expenses include plant operation costs, feed and cooling water, and field maintenance costs [4]. It is expected that as new plants become larger, the costs will decrease proportionally. We have considered in this work, based on the average of reported values, annual operation and maintenance costs of 1.5% and 2% for PV [1,49,61,79–81] and CSP systems [7,65], respectively, of the total cost of the system, C(t).

4.2.2. Insurance costs

Owing to the relatively high technological risks associated with PV and CSP systems, in contrast with conventional ones, an insurance policy should be adopted. The annual insurance rate for PV systems is taken as 0.25% [75] of the capital cost of the system, $C(t)$, while for CSP system this value increases to 0.5% [30,65].

4.3. Factors related to future costs

The factors that determines future system cost reductions are, as observed in Eq. (13), the learning rate, *LR*, and the future cumulative installed capacity, $Q(t)$.

4.3.1. Learning rates

For PV systems several closely related learning curves have been elaborated for different periods, including the one represented in Fig. 3, with values that range between 15% and 25% [44,46,50,82–85]. In the case of CSP, the learning curve that we have elaborated in Fig. 3 shows a learning rate of around 11%. In this work we will assume the more conservative estimations of the International Energy Agency. The IEA recommends learning rates of 18% for PV systems [1,20] and 10% for CSP systems [4,20] from 2010 onwards. The learning rate is applied to the whole system, even in the case of PV systems, since it has been found that "balance of system" (BOS) experience curves show similar learning rates than modules [46,83,86,87].

4.3.2. Cumulative installed capacity

The beginning of 2010, when the cumulative installed capacity, $Q(0)$, was 22.88 GW for PV systems and 0.82 GW for CSP systems (see Figs. 1 and 2), has been taken as the reference year for our study of the cost evolution of PV and CSP electricity. In addition, we represent in Table 1 the objectives elaborated by the IEA for $Q(t)$ for the BLUE and Roadmap Scenarios. According to the BLUE Map Scenario, PV and CSP systems would provide 6% and 5%, respectively, of the annual global electricity production in 2050 [20]. The Roadmap Scenario is more ambitious, and predicts that in 2050 PV and CSP systems would provide around 11% each of the annual electricity production [1,4].

When an objective is set to 2050 it could be reached in many different ways, for example, by means of a linear function, an exponential, a potential, a polynomial, or a logistic curve ("S" curve). However, the existence of intermediate objectives within the 2010–2050 interval limits the possibilities to those that best fit those objectives. Based on the values exposed in Table 1, we next proceed to estimate the analytical equations for the cumulative installed capacity in a year *t*, $Q(t)$, that best fit them. In all cases, but in the Roadmap Scenario for CSP systems, the function that best fit the data is the logistic function ("S shaped curve"), whose equation for a year *t*, after 2010, is [88]:

$$Q(t) = \frac{e^{r\cdot(t-2010)}}{(1/Q(0)) - (1/M) + (e^{r\cdot(t-2010)}/M)} \tag{14}$$

where $Q(0)$ and M are the initial and maximum cumulative installed capacities, respectively, and r is the growth parameter. However, the best fitting function corresponding to the Roadmap Scenario for CSP systems is a second grade polynomial. These analytical equations have been summarized in Table 2 and have also been plotted in Fig. 4, together with the final and intermediate objectives of $Q(t)$ for each scenario.

Table 1
PV and CSP cumulative installed capacity at the beginning of 2010 (see Figs. 1 and 2) and objectives, in GW, for the BLUE Map [20] and Roadmap Scenarios [1,4].

Scenario	PV					CSP				
	2010	2020	2030	2040	2050	2010	2020	2030	2040	2050
BLUE map (GW)	22.88		150		1150	0.82		250		630
Roadmap (GW)	22.88	210	872	2019	3155	0.82	148	337	715	1089

Table 2
Specific parameters for the cumulative installed capacity evolution for the IEA BLUE map and roadmap scenarios for PV and CSP systems.

Technology	Scenario	Function	Parameters of $Q(t)$
PV	BLUE map	Logistic	$Q(0)=22.88$ GW; $M=7000$ GW; $r=0.102$
	Roadmap	Logistic	$Q(0)=22.88$ GW; $M=3450$ GW; $r=0.185$
CSP	BLUE map	Logistic	$Q(0)=0.82$ GW; $M=630$ GW; $r=0.32$
	Roadmap	2nd grade polynomial	$Q(t)=0.459$ GW $(t\text{-}2010)^2+9.073$ GW $(t\text{-}2010)+0.82$ GW

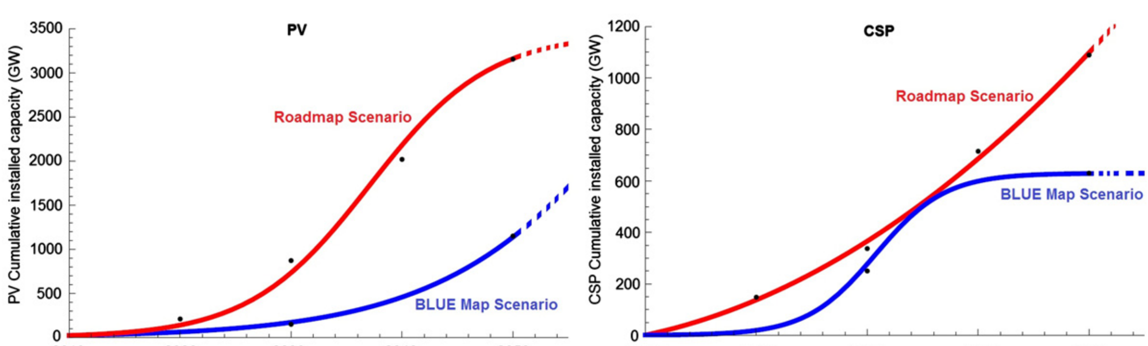


Fig. 4. Objectives (Table 1) and suggested cumulative installed capacity curves (in GW) for PV and CSP systems for the IEA BLUE Map and Roadmap Scenarios.

4.4. Electricity production

Here we include all the variables that determine the amount of energy from the sun which can be converted into electricity for the PV and CSP systems.

4.4.1. Solar resource

The solar resource, *S*, accounts for the average annual energy per unit area (kW h/m^2/yr) reaching the location where the systems are installed. As it is well known, PV and CSP technologies make use of different solar resources. Whilst PV system take advantage of both direct and diffuse irradiation, CSP systems do not capture its diffuse component since it cannot be optically concentrated. In this sense, these technologies can be considered as somewhat complementary, depending on the nature of local solar irradiation. CSP developers typically set a bottom threshold for DNI of 1900 kW h/m^2/yr to 2100 kW h/m^2/yr [4,65] in order to achieve a reasonable economic performance.

In the case of PV systems, the solar resource is constituted by the global irradiation, i.e., the sum of direct and diffuse irradiations. Since fixed, optimally-inclined south-oriented PV systems have been taken as reference in our analysis, the annual global irradiation should be given under these circumstances. For comparison purposes we will consider a wide range for the values of the global irradiation that goes from 1300 to 2300 kW h/m^2/yr, and that includes places as unfavorable as Germany [89,90]. For CSP systems the solar resource is only constituted by the direct solar irradiance perpendicular to the surface of a receptor that should be continuously tracking the sun (Direct Normal Irradiance, DNI). The values of the DNI corresponding to a given location are strongly influenced by the composition of the atmosphere and the weather. As mentioned in Section 2, the major CSP technology markets are currently located in the Southwest of the United States and in Spain. Consequently we consider a DNI which ranges from 2000 to 2850 kW h/m^2/yr [7,67,71,91,92].

4.4.2. Tracking factor

The tracking factor (*TF*, dimensionless) adjusts the solar resource to the real incident usable solar energy over the system due to its orientation. PV systems can be set fixed, on a flat surface tilted towards the south (in the northern hemisphere), or can incorporate trackers, either of single or double axis. In general, it has been considered that the lowest cost of PV electricity is obtained with optimally-inclined fixed modules [93,94], since the increase of the electricity produced would not compensate the increase of the cost of the system due to the tracking system. Consequently and since the solar resource for PV systems has been given under these favorable circumstances, the tracking factor should be equal to 1.

CSP systems, since they only use direct solar irradiation, should always incorporate tracking systems. Power tower and parabolic dish collectors incorporate a double axis tracking system, thus the direct solar irradiation received by these systems is equal to the value of the DNI, and therefore the tracking factor is 1. However, the direct solar irradiation received by parabolic trough, our reference systems, and linear Fresnel systems is lower than the DNI, since they only incorporate a single axis tracking mechanism. Doing the average of the correlation between the direct solar irradiation over a single axis and a two axis tracking system for 50 different locations, it has been found [34] that the single axis system accounts for the 97.11% of the radiation of the two axis one, and therefore the tracking factor should be 0.9711.

4.4.3. Performance factor

The performance factor (η) converts the kW h/m^2 of the solar resource utilized per year, after including the tracking factor, into the real amount of electricity produced by the system per installed watt, and therefore it should be expressed in m^2/kW units. PV systems are characterized under standard-test conditions and their power is given in watts peak (Wp). Since the instantaneous power output of the systems scales with solar irradiation, the electricity produced ideally per Wp installed is obtained just multiplying the number of kW h/m^2 of the corresponding solar resource per the electricity produced per one Wp during one peak hour (1 W h/Wp), and dividing it by the solar resource during one peak hour (1 kW h/m^2). The consequence is that the number of kW h/m^2 of the solar resource equals the number of kW h/kWp ideally produced. The fact that they are the same numerically is a consequence of the rated watts being defined at 1000 W/m^2 [75]. However, to obtain the real electricity production per Wp we also need to know how close the PV system approaches ideal performance (the corresponding to the so-called standard-test conditions) during real operation. Since PV modules are characterized under DC conditions, it is necessary to take into account the conversion into AC, being the maximum efficiency of the inverters between around 93–95% [15,74]. Furthermore, the PV modules efficiency decreases linearly with temperature respect to their efficiency at 25 °C [95–99], i.e.,:

$$\eta_{\mathrm{PV}} = \eta_{\mathrm{PV},T=25^{\circ}C}\left(1-\beta\left(T-25^{\circ}C\right)\right) \tag{15}$$

where β is the temperature coefficient of solar cell efficiency and the module temperature (T) depends on the ambient temperature, the solar irradiance and the wind speed. Therefore, the performance factor for PV systems includes the overall effect of conversion from DC to AC, and of losses on a PV array's power output depending on cell temperature [74]. Taking all of these factors into account, the real efficiency ranges between 75% and 85% of the ideal efficiency [15,61,74,75,100]. Thus, we will use in this work performance factors for PV systems of 0.75, 0.8 and 0.85 m^2/kWp for a PV solar resource of 2300, 1800 and 1300 kW h/m^2/yr, respectively, assuming that its value is virtually independent of the plant size [18].

Unlike PV systems, CSP plants produce directly AC electricity, and their power output is not characterized by the solar field, but by the power of their turbines. The differences of the value of the performance factor (η) of the CSP plants are mainly determined by the amount of thermal storage. We have considered in this work two reference plants with difference amounts of thermal storage in order to estimate their corresponding performance factor. They are SEGS V in California, without any thermal storage, and Andasol I in Spain, which has 7.5 h of thermal storage. Taking into account the average annual solar gross production, the power of the plant, the tracking factor and the solar resource for the considered plants, we have estimated a solar resource of 0.853 and 1.602 m^2/kW for a plant without any thermal storage and with 7.5 h, respectively [8].

4.4.4. Degradation factor

Due to the intrinsic yearly degradation of solar systems, they should slightly diminish their production of electricity as time proceeds. For PV systems an annual output drop of 0.6% [5,6,101,102], mainly as a result of module exposure to ultraviolet radiation, has been considered, whilst for CSP systems this value is lower, of about 0.2%, due mainly to the degradation of the turbines [103].

4.5. Financial factors

4.5.1. Discount rate

One of the most important assumptions on the input parameters to the LCOE is related to the value of the discount rate, which takes into account the time value of money as well as the risk of the investment. PV and CSP systems are associated with greater technological risks when compared with traditional power plants, and therefore they will be associated with higher discount rates. The value chosen for the discount rate must be carefully assessed since it can influence the investor decision towards one option or another [39]. The International Energy Agency assumes conservative discount rates between 10% and 12% for PV systems and between 10% and 15% for CSP systems [104]. According to this, and even though lower discount rates of about 5% have been reported for PV [1,61,79] and for CSP systems [4,34,52], we will assume in most cases discount rates of 10% and 12% for PV and CSP systems, respectively.

4.5.2. Lifetime of the systems

The lifetime of the systems is a determinant factor when estimating the LCOE of the solar plant and, therefore, if its real value does not correspond with the estimated one, the economic feasibility of the project can be seriously affected. PV modules, the key component of PV systems, are warranted for a duration in the range 25–30 years by most producers [1,105–107], and therefore we will assume this value. For CSP systems we will consider a useful lifetime of 30 years, as estimated by most studies [1,33,63,108], although other estimations forecast lifetimes of 40 years [109].

5. Results and discussion on the applications of the model

Once we have described the model in the previous sections, we will apply it now to some typical cases. First we will perform in 5.1 a sensitivity analysis of some of the main variables that affect the LCOE. Later we will compare in 5.2 the future cost evolution, between 2010 and 2050, of PV and CSP electricity under different situations. Finally in 5.3 we will estimate the year in which these two solar technologies will achieve grid parity. We will assume, unless otherwise stated, a set of typical values for the different input variables of Eqs. (8) and (13) which are specified in Table 3. Note that for the solar resource and the discount rate we have considered a wide range of values due to the large influence of these variables on the LCOE. For the discount rate, except in Fig. 6 where we directly compare the influence of this variable in the LCOE, we assign values of 10% and 12% for PV and CSP systems, respectively (see Section 4.5.1).

5.1. Sensitivity analysis

We have considered, as other studies [7,35,110,111], the available solar resource and the financial discount rate as the most significant variables for doing a sensitivity analysis of the LCOE corresponding to PV and CSP systems. In Fig. 5 we represent the sensitivity analysis for the solar resource both for the value of the LCOE in 2010 and our prediction for 2050 (see Section 5.2) for a cumulative installed capacity equivalent to that predicted by the BLUE Map and Roadmap Scenarios. For PV systems, since they take advantage of both direct and diffuse irradiation, we have considered a wider range of values for the solar resource than for CSP systems.

Table 3
Typical values for the cost evolution of PV and CSP electricity calculations.

Factor	Symbol	Units	PV	CSP
Cost of the system installed in 2010	$C(0)$	\$/W	4	4.2
Cumulative installed capacity in 2010	$Q(0)$	GW	22.88	0.82
Cumulative installed capacity in a year t	$Q(t)$	GW	Table 2	Table 2
Learning rate	LR	%	18	10
Land cost	L	\$/kW	30	24
Discount rate	r	%	3–15	3–15
O&M costs	O&M	%	1.5	2
Annual insurance rate	I	%	0.25	0.5
Solar resource	S	kW h/m^2/year	1300–2300	1900–2850
Tracking factor	TF	Dimensionless	1	0.9711
Performance factor	η	m^2/kW	0.75	0.853
Lifetime of the systems	N	Years	25	30
Annual output degradation rate	d	%	0.6	0.2

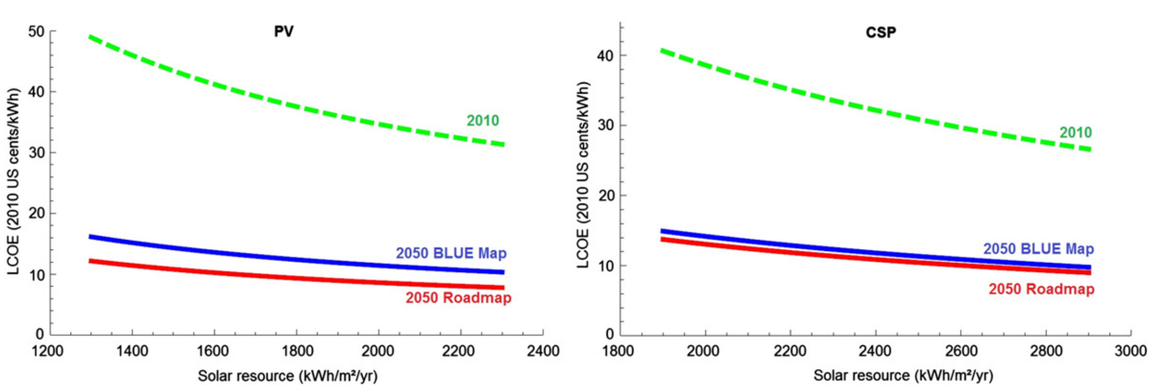


Fig. 5. Sensitivity analysis of the LCOE in 2010 and in 2050 for the IEA BLUE Map and Roadmap Scenarios as a function of the global irradiation for PV systems and of the direct normal irradiation for CSP systems.

Consequently, and according to Section 4.4.1, we have considered global irradiations (on optimally-inclined surfaces) from 1300 to 2300 kW h/m^2/yr for PV systems, and direct normal irradiations from 1900 to 2850 kW h/m^2/yr for CSP systems. It can be observed from Fig. 5 that the LCOEs of PV systems decrease at a relatively slower rate, with the increase of the available solar resource than in the case of CSP systems. This can be attributed to the drop of the efficiency of PV cells with temperature, as discussed in Section 4.4.3.

We have also carried out a sensitivity analysis of the LCOE in terms of the discount rate (Fig. 6) to show the large influence of this parameter in the economic feasibility of a project. We have compared a wide range of values, from discount rates of around 3%, corresponding to some governments financial rates, to as high as a 15% (see Section 4.5.1). The values considered for the solar resources are 2300 and 2850 kW h/m^2/year for PV and CSP systems, respectively (see Section 4.4.1). It can be observed from Fig. 6 than the LCOE can even double when comparing the lowest and highest values of the discount rate. Usual discount rates in the private sector for solar technologies are somewhat high due to a relatively high risk perception about them. Political and legislative instability also negatively affects the discount rates of these technologies, since the economic feasibility of the project usually depends on feed-in tariffs concessions. It is also important the economic situation of a specific country, whose difficulties to finance in a moment of debt crisis can penalize the funding of new projects. However, as solar markets evolve and the technologies become more mature, discount rates should decline over time.

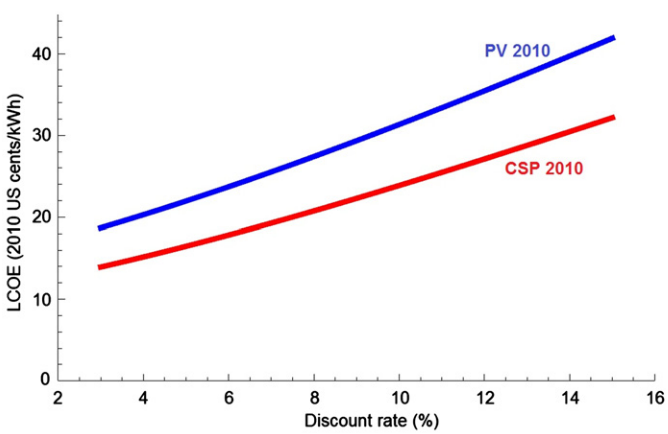
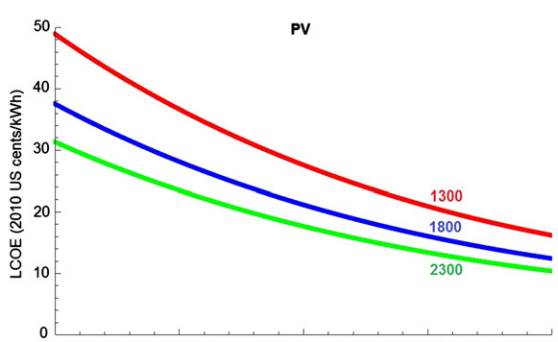


Fig. 6. Sensitivity analysis of the LCOE in 2010 for PV and CSP systems as a function of the discount rate.

5.2. LCOE future evolution

By making use of Eq. (13), in this section we compare the future evolution, between 2010 and 2050, of the LCOE corresponding to PV and CSP systems under different situations. First, in Figs. 7 and 8, we compare different solar resources for the BLUE Map and Roadmap Scenarios, respectively (see Fig. 4). For PV systems we compare global irradiations of 1300, 1800 and 2300 kW h/m^2/yr corresponding, respectively, to locations in Germany [90], central Spain [90] and California [89]. For CSP systems we compare direct normal irradiations (DNI) of 2000, 2400 and 2850 kW h/m^2/yr corresponding, respectively, to some places in southern Spain [7,92,112–114], the north of Africa [26,30,67,91] and California [7,71]. The high value of the learning rate corresponding to PV systems, of about 18% (Section 4.4.1), allows for progressive and sustained electricity cost reductions. Due to the higher objectives of the Roadmap scenario, it can be deduced from Figs. 7 and 8 that PV electricity cost reductions are higher in this scenario than in the BLUE Map, especially during the first two decades. However, the differences are not as great in the long term (2050), when the cost of the electricity represents 33% and 25% of its value in 2010 for the BLUE Map and Roadmap scenarios, respectively. For CSP systems the electricity cost reductions are more noticeable during the first two decades, especially during the 2010–2020 period in the case of the Roadmap scenario (see Fig. 8). The cost of CSP electricity in 2050, with respect to its value in 2010, represents the 37% and the 34% in the BLUE Map and Roadmap scenarios, respectively.

On Fig. 9 we directly compare the evolution of the LCOE for PV and CSP systems for the BLUE Map (a) and Roadmap Scenarios (b) for a solar resource typical of Southern Spain. We have chosen this geographical area because it corresponds to the threshold value of direct solar irradiation below which CSP systems are not economically viable. Therefore, we have assumed a DNI of 2000 kW h/m^2/yr for CSP systems [7,92,112–114], and a global irradiation of the same value for PV systems [90] with a corresponding performance factor 0.78 m^2/kWp, as follows from Section 4.4.3. Under these circumstances, we have obtained somewhat similar costs for the electricity generated by PV and CSP systems as observed in Fig. 9. However, in Southern Spain, utilities may prefer CSP systems due to the possibility of thermal storage and fossil fuel hybridization which can provide a better supply security. It is also interesting to observe in Fig. 9 the initial higher values of the slopes of the curves, i.e., larger cost reductions, corresponding to CSP electricity, which according to our mathematical model can be attributed to the larger initial relative growth of the cumulative installed capacity. However, in the long term, due to the higher learning rate of PV systems, their electricity costs will be lower than the corresponding to CSP systems.



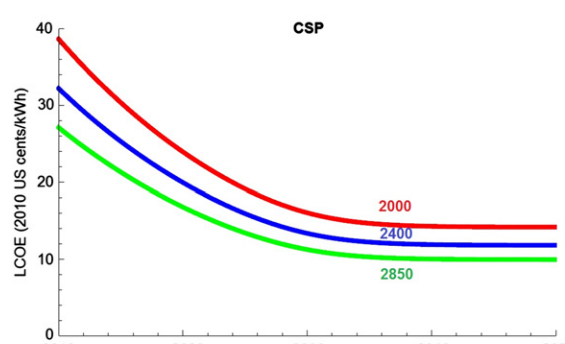


Fig. 7. LCOE evolution for different solar resources for the BLUE Map Scenario: for PV systems global irradiation of 2300, 1800 and 1300 kW h/m^2/yr, and for CSP systems DNI of 2850, 2400 and 2000 kW h/m^2/yr.

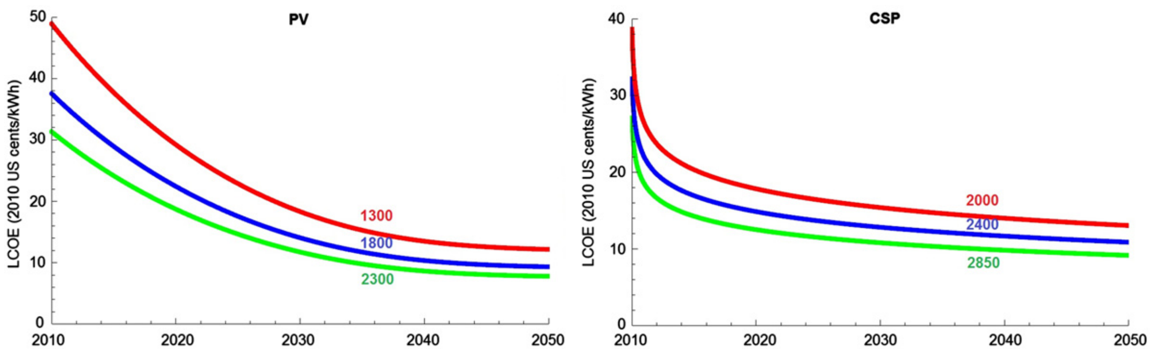


Fig. 8. LCOE evolution for different solar resources for the Roadmap Scenario: for PV systems global irradiation of 2300, 1800 and 1300 kW h/m^2/yr, and for CSP systems DNI of 2850, 2400 and 2000 kW h/m^2/yr.

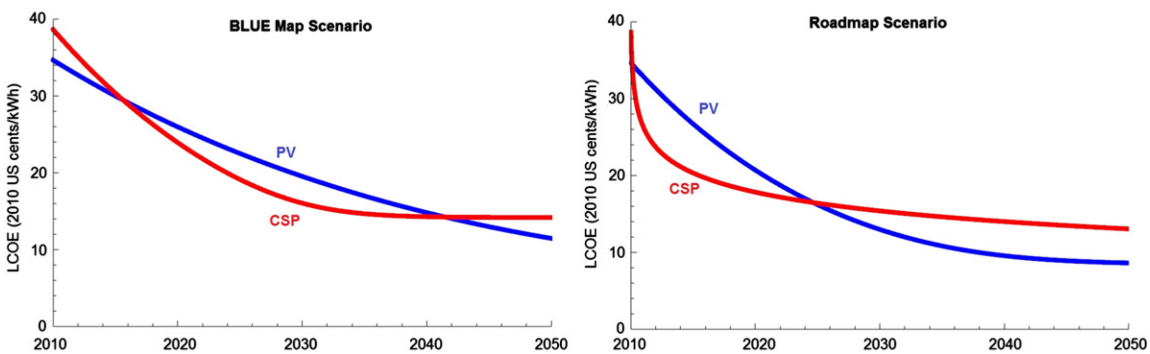


Fig. 9. PV and CSP LCOE evolution for the BLUE Map and Roadmap Scenarios for a global irradiation of 2000 kW h/m^2/yr for PV systems and a DNI of 2000 kW h/m^2/yr for CSP systems.

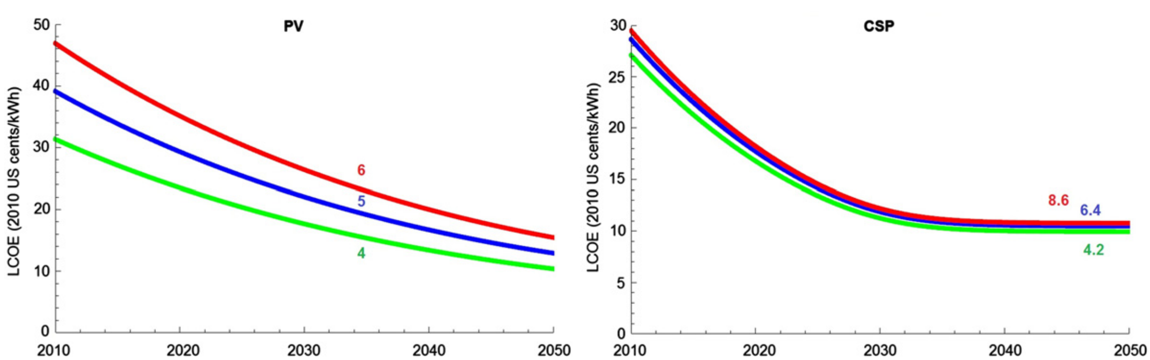


Fig. 10. LCOE evolution for different costs of the systems in 2010 for the BLUE Map Scenario. For PV systems we compare cost of 4 $/W (utilities), 5 $/W (commercial) and 6 $/W (residential). For CSP systems we compare cost of 4.2 $/W (no storage), 6.4 $/W (intermediate case) and 8.6 $/W (7.5 h storage).

Finally, in Figs. 10 and 11, we compare the future evolution of the LCOE for different initial (2010) values of the cost of the systems (see Section 4.1.1) for the BLUE Map and Roadmap Scenarios, respectively. For PV systems we compare the cost evolution for systems of different size scale, corresponding to 4 $/W (utility scale), 5 $/W (commercial scale) and 6 $/W (residential scale). In the case of CSP systems we compare costs of systems with different amounts of thermal storage corresponding to 4.2 $/W (no storage), 6.4 $/W (intermediate case) and 8.6 $/W (7.5 h of storage). The values considered for the solar resources have been 2300 and 2850 kW h/m^2/year for PV and CSP systems, respectively (see Section 4.4.1).

Whilst for PV systems the LCOE and the cost of the systems are highly correlated, this is not the case of CSP systems since the increase of the cost of the system, due to its higher amount of thermal storage, also increases its performance factor, as explained in Section 4.4.3, so the corresponding LCOEs hardly vary, as confirmed by other studies [70,110]. What actually is being compared in Figs. 10 and 11 are different size scale systems for PV systems, and different amounts of thermal storage for CSP systems. CSP constitutes by its nature a centralized power generation technology, and it can be observed from Figs. 10 and 11 that its LCOE is not very different from the one corresponding to PV utility scale systems ($C(0)=4$ $/W). The highest PV electricity costs are, as expected, those corresponding to residential scale PV systems ($C(0)=6$ $/W), but these extra costs can be partially compensated by savings in distribution. With regard to CSP systems, since there are not significant differences in the LCOE for the three different cases presented, utilities will often prefer the option with the larger amount of thermal storage ($C(0)=$ 8.4 $/W), due to its higher flexibility and security in energy supply that allows to keep on producing after sunset, when the demand and the price of the electricity is higher. Therefore, the thermal storage would allow a higher penetration of CSP technology in the

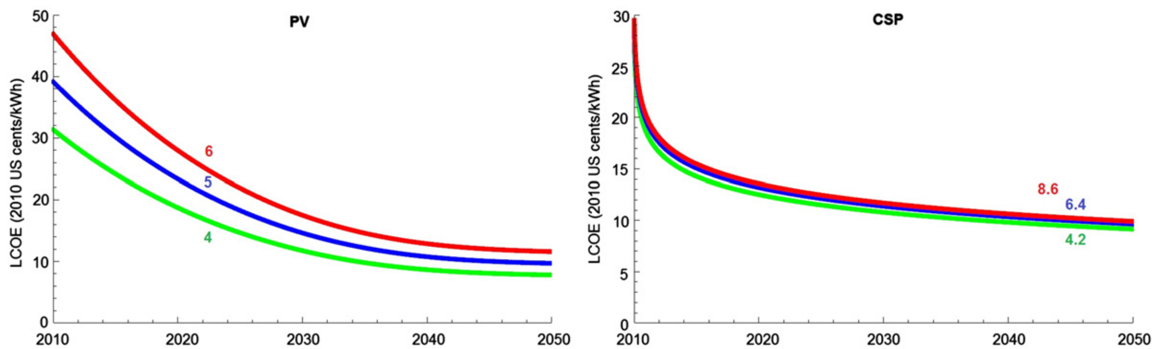


Fig. 11. LCOE evolution for different costs of the systems in 2010 for the Roadmap Scenario. For PV systems we compare cost of 4 $/W (utilities), 5 $/W (commercial) and 6 $/W (residential). For CSP systems we compare cost of 4.2 $/W (no storage), 6.4 $/W (intermediate case) and 8.6 $/W (7.5 h storage).

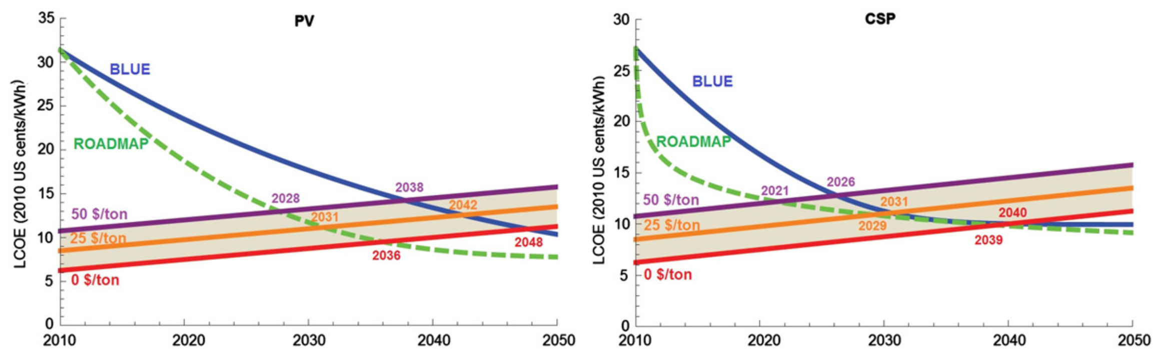


Fig. 12. PV and CSP LCOE evolution for the BLUE Map and Roadmap Scenarios for relatively favorable conditions and grid parities calculations for coal-fired thermal power plants with a carbon emission price of 0, 25 and 50 $/ton CO_2.

energy mix [71,115], what constitutes an advantage with respect to other intermittent renewable energy sources, like PV systems [116,117].

5.3. Grid parities

In Fig. 12 we estimate, under relatively favorable conditions and for the two scenarios considered in this work, the years when PV and CSP electricity will reach grid parity, i.e., when solar electricity costs will equal those of conventional electricity. To this end, the cost evolution of conventional electricity has also been evaluated in a simple manner by assuming that it is generated in coal-fired thermal power plants, since, for example, almost half of the electricity in the United States and more than three quarters in China is produced in this kind of plants [104]. Only production costs of electricity will be considered and, consequently, transport and distribution costs will not be included. The current real production cost of electricity generated by coal-fired thermal power plants is 6.26 US cents/kW h [51], and production costs of power plants in the United States have increased an average of 3.5% annually during the last 6 decades [101]. However, due to the high accessibility of coal, we have considered that the cost of electricity from coal would in the future increase linearly in real value (net of inflation), and have assigned it an annual conservative growth rate of 2%. In addition, grid parities will be also estimated for the cases when a penalty is added to coal-fired thermal power plants due to their CO_2 emissions. Therefore, assuming an emission factor of 0.9 kg CO_2/kW h [104,107,118], we consider in Fig. 12 two cases: a carbon emission price of 25 $/ton CO_2, that is approximately equal to the price considered in the European Union emission trading system [67], and a price of 50 $/ton CO_2, as recommended by the IEA BLUE Map Scenario [20].

Under favorable conditions, especially in the case of relatively high solar resources, and for a carbon emission price of 50 $/ton CO_2, PV systems will reach grid parity between 2028 and 2038, depending on the scenario followed by the cumulative installed capacity, while CSP systems would reach it between 2021 and 2026. For a carbon emission price of 25 $/ton CO_2 grid parity would be delayed 3 years for PV systems and between 5 and 8 years for CSP systems. In the unlikely case that no future penalties would be applied to coal-fired thermal power plants, then grid parity would be reached between 2036 and 2048 for PV systems and around 2040 for CSP systems. Other studies have reported earlier grid parities for PV and CSP systems, but for this to happen, in addition of very high solar resources all year around, the conventional electricity prices have to be relatively expensive, as in the case of some islands, like for instance Hawaii, where the cost of electricity almost triples its value in continental United States [119]. At this point, it is also interesting to remark that grid parities would had not varied much if we had taken as reference the electricity produced by natural gas, which is presently increasing in percentage in the electricity mix of developed countries. This is due to the fact that the slightly higher cost of this electricity would be compensated by their lower CO_2 emissions [104].

It can be observed from Fig. 12 that cost reductions are higher on the Roadmap Scenario, particularly at the initial stages. However, in the long term (2050) the differences between the costs of electricity for both scenarios are not very large. Indeed, for PV systems the LCOE in 2050 are 10.4 and 7.8 US cents/kW h for the BLUE Map and Roadmap scenarios, respectively. For CSP systems these differences are even smaller, since from 2030 onwards the LCOE for both scenarios are practically the same, being in 2050, 9.9, and 9.2 US cents/kW h for the BLUE Map and Roadmap scenarios, respectively.

6. Summary and conclusions

We have presented in this paper a mathematical model for the calculation of the LCOEs for PV and CSP electricity, based on the discounted cash flow techniques and the learning curve approach, which yields analytical closed-form expressions for the calculation of the LCOEs, and their future evolution. By making use of a simple computer simulation program, the resulting expressions can be directly plotted in a continuous manner, thus generating graphs showing the evolution of the LCOEs for the 2010–2050 time interval. The expressions found for the LCOEs depend on twelve independent variables, among them the solar resource, discount rate, initial cost and lifetime of the systems, operation and maintenance costs, etc. Some of these variables strongly influence the LCOEs and therefore it is recommended in these cases to carry out the corresponding sensitivity analyses.

From the results presented in this paper, we can reach the following conclusions: (i) If the IEA Scenarios are accomplished, then, according to our model, solar electricity costs for CSP would be reduced substantially in the next two decades (2010–2030), but, from there on, the costs will be reduced at a much slower rate. In the case of PV, the LCOE cost reductions will be slower at the beginning, but, in the long run, they could diminish at a higher rate than CSP. (ii) For PV systems, the LCOE and its evolution is practically proportional to the initial cost of the systems. However, in the case of CSP systems, although the initial cost of the system widely varies depending on the thermal storage capabilities, the results obtained for the LCOEs are practically the same. (iii) The future evolution of the LCOE(t) costs for solar electricity (PV and CSP) depend not only on the corresponding learning rates, and the targeted values for the cumulative installed capacity function $Q(t)$, but, in addition, they are also strongly influenced by the specific curved time-paths followed by this function. (iv) The performed sensitivity analyses show that the solar electricity LCOE costs are strongly influenced by, both, the value of the discount rate, and the local solar resource. Consequently these parameters also largely affect the number of years necessary to reach grid parities. (v) Among solar technologies, PV would be more appropriate than CSP for middle to high latitudes, especially in locations of partly cloudy weather. On the other hand, CSP develops its highest potential in arid or semi-arid areas like those located at the Earth's "sun-belt" (latitudes 20–40 degrees).

In addition, the results of this paper can be of interest in energy planning policies, like for example those related to financial subsidies to renewable energies in the form of tax deductions, preferential loans, etc. The results on the future evolution of solar electricity costs can also be of help to governmental policies related to subsidies to utilities, since a relation can be established between the values of the tariff-in and the expected decrease of the costs of energy generated by solar systems. Finally we would like to remark that, due to the fact that solar techniques are capital intensive, the values of the discount or interest rates on the loans are essential for the right funding of the project, as we have proven in our sensitivity analysis. Therefore, a proper negotiation of the loans is essential for the financial success of the projects.

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